Commonwealth of Massachusetts
Office of Consumer Affairs & Business Regulation
Division of Energy Resources

Renewable Energy Portfolio Standard Notice of Inquiry Regarding Some Proposed Revisions of the Regulations Pertaining to the Definition of "Low-Emission, Advanced Biomass Power Conversion Technologies"	))))))

Joint Comments of
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Burlington Electric Department
and
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These comments are jointly offered by the above-noted business entities in response to the Notice of Inquiry Regarding Some Proposed Revisions of the Regulations Pertaining to the Definition of "Low-Emission, Advanced Biomass Power Conversion Technologies" (the "NOI"), issued on July 1, 2005 by the Division of Energy Resources ("DOER") and the Department of Environmental Protection ("DEP").

These comments address the following issues raised by the NOI: (1) Removal of the Categorical Exclusion of Stoker-Grate Biomass Generating Units from Renewable Portfolio Standard ("RPS") Program Eligibility, (2) The Retrofit Requirement and the 36 month Limitation on RPS Program Eligibility, (3) The Advanced Biomass Power Conversion Technology Performance Standard, (4) The Low Emissions Performance Standards, and (5) Miscellaneous Issues. Each of the first four topics is organized into three parts; the first part summarizes the applicable NOI proposal concept, the second part consists of discussion points on the NOI proposal concept, and the third part presents our recommendations. The Section 5 miscellaneous comments combine the discussion of the point raised and our recommendation.

1.0 REMOVAL OF THE CATEGORICAL EXCLUSION OF STOKER-GRATE BIOMASS GENERATING UNITS FROM RPS PROGRAM ELIGIBILITY.

1.1 NOI Proposal

(a) The NOI seeks to create a level playing field for biomass combustion technologies by proposing at page 5 of the NOI the removal of the RPS regulation that excludes "pile burn, stoker combustion or similar technologies" from RPS eligibility. According to the

NOI at page 14, DOER seeks to repeal this exclusion in part to increase the number of RPS-eligible generators and eliminate a recognized shortage of renewable energy certificates. This will have the desired effect of preventing the closure of a number of biomass generating facilities and the consequent erosion of renewable generating capacity. Id. In essence, the NOI proposes to allow RPS eligibility for biomass generating units if the units can meet the low emissions performance standards and the advanced biomass power conversion performance standards of the NOI. NOI at 9.

1.2 Discussion Points

(a) As noted above, a key goal of the NOI's proposed removal of the RPS categorical exclusion of stoker-grate generating units is to increase the amount of generating units participating in the RPS program and thereby add to the supply of renewable energy credits available for sale. This is an important goal, in part, because the actual on-line capacity of renewable power, as a percentage, in New England has been decreasing. In October, 2004, ISO-NE issued the Renewable Transmission Expansion Plan and its Technical Report. Table 11.7 of the Technical Report states that, in the year 2000, 10.4% of New England generation was renewable. By 2003, only 7.3% of New England's generation was defined as renewable. Technical Report at page 167, Table 11.7. The scarcity of renewable energy generating units generally, and of those which meet the RPS eligibility criteria, has an adverse impact on the supply of renewable energy credits. As noted in the DOER's Annual RPS Compliance Report for 2003 at page 7, this shortfall in renewable credits is estimated to produce at least 15 million dollars of alternative compliance payments in 2004. The Compliance Report at page 11 also notes the great value of the RPS program in promoting a diversified electric generation portfolio in the New England region, but recognizes that constraints on the development of new renewable projects, such as siting, financing, and the lack of long term contract availability are real barriers to the increase in RPS eligible projects and the supply of renewable credits. Given these factors and circumstances, the NOI's proposed removal of the categorical exclusion of stoker units coupled with the policy providing for the sale of the entire output of a retrofitted unit over a reasonable time period is the correct balance of policy interests. Inclusion of retrofitted stoker units in the RPS will reduce the shortfall of credits, put downward pressure on the amount of alternative compliance payments, significantly reduce NO_x air emissions levels below those allowed for other existing RPS biomass participants, and provide for the continued support of a viable RPS program thereby providing the time needed for other forms of renewables to potentially solve siting and financing issues.

(b) The NOI's proposed removal of the categorical exclusion of stoker units from RPS program eligibility is an important step in creating a level playing field in the RPS for renewable biomass technologies. One can, however, remove the categorical exclusion of stoker units from RPS program eligibility and still, as a practical matter, preclude stoker unit participation in the RPS program if the other regulatory requirements for RPS participation are such that they operate, unintentionally and indirectly, to preclude stoker unit eligibility.

The NOI's net heat rate requirement for the advanced biomass power conversion technology performance standard is an example of a potential regulatory requirement that has an unintentional preclusive effect on stoker unit participation in the RPS, even if the stoker

categorical exclusion is removed. As discussed in Section 3 of these comments, the requirement, for example, that stoker units in the 10 MW to 25 MW range must retrofit or retool to meet a 13,000 Btu/KWh net heat rate is an unattainable standard. While stoker units can operate with, for example, lower NO_x emissions than other biomass units already deemed RPS eligible, it is unlikely that any existing stoker unit can do so at a 13,000 Btu/KWh heat rate. Heat rates in this range are unattainable due to the original steam cycle designs of the existing units, high moisture content of the renewable fuel combusted and the increased parasitic load created by the operation of air pollution control equipment added to meet RPS low emission requirements.

Moreover, no retrofit device or practice, other than a complete steam cycle change which is not a practical option because it is cost prohibitive, can be employed on an existing stoker unit that would make a 13,000 Btu/KWh heat rate attainable. Note that the option of replacing a stoker unit's boiler with a fluid bed boiler was an available option, prior to the NOI, by which to meet the advanced biomass power conversion standard, but according to the NOI, this would result in a *higher* heat rate (16,000 Btu/KWh in the case of the 10 MW to 25 MW unit) than the NOI provides for stoker units. This retrofit option does not appear to be an optimum choice for NOI heat rate compliance because it requires significant capital expenditures but does not thereby change the heat rate or produce any improvement in air emissions compared to the heat rate and air emissions resulting from a stoker unit with add-on pollution controls. A stoker unit with add-on pollution controls will have a heat rate similar to that accorded to fluid bed units under the NOI. Note that a fluidized bed unit will also experience a heat rate increase due to the addition of the add-on pollution control technology needed to meet the NOI's low emissions standards.

To remedy the potentially preclusive effect of this standard on stoker unit RPS participation, our recommendation in Section 3.3(b), presents a reasonable and commercially attainable method for determining whether a unit is an advanced biomass power conversion technology.

Similarly, the NOI low emissions performance standards, if set at or near the NOI Table 3 limits, will operate to preclude stoker unit or fluidized bed unit participation because those limits are unlikely to be commercially obtainable. In contrast, Table 2 air emission limits are commercially attainable, represent a significant reduction of air emissions, and will not operate to preclude program participation by biomass units. Our comments at Section 4 provide recommendations on attainable emission levels for biomass units, including recommending a NO_x level of .065 lbs/mmBtu.

Stoker unit RPS program participation can also be adversely affected, notwithstanding the NOI's proposed removal of the stoker categorical exclusion, by proposals to limit the length of time such units can participate in the RPS program, and by proposals to allow stoker units to sell only a portion of their output as RPS eligible or to sell their entire output as RPS eligible but at some reduced or "tier-II type" price. These limitations on renewable energy credit revenue stream are as real a barrier to entry into the RPS as is the inadvertent establishment of other commercially unattainable RPS regulatory standards. No other technology that meets the low emission advanced biomass power conversion standard is subject to similar limitations, or inquiries into, or limits on, perceived profitability. According to comments made at the July 28,

2005 Stakeholder's Meeting, the expected base case scenario for renewable energy credits ranged from $23 to $26 per credit from 2003 to 2012. See Grace, Cory, *Massachusetts RPS: 2002 Cost Analysis Update – Sensitivity Analysis* at 20 (December 16, 2002). Notwithstanding the fact that credits currently trade in excess of these levels, no RPS technology has its eligibility determined based on credit amount limitations or credit price differentials.[1]

RPS program time limitations and credit pricing differentials are particularly problematic when undertaking the business decision of whether to incur the costs necessary to make a stoker unit RPS eligible. The capital costs of air emissions compliance (assuming NOI Table 2 limitations are applicable) can be in the range of between six to in excess of ten million dollars, and the addition of add-on pollution control equipment will increase the operating costs of the unit over its life. These increases in annual operating costs for some types of add-on controls for a 10 MW to 25 MW range unit can be in the $500,000 to $1,000,000 range. Larger units can have increased annual operating costs in excess of $1,250,000 exclusive of additional costs due to required periodic CO catalyst replacement. These expenses are certain to occur; however, the revenue from renewable energy credits to offset these expenses is not guaranteed. Given the uncertain nature of the revenue stream, our point is that RPS requirements limiting or reducing the already uncertain level of renewable energy credit revenue impose more uncertainty into the business decision of whether to deploy the capital in the first instance to bring a stoker unit within the RPS program eligibility requirements of low emission and advanced power conversion.

(c) The RPS legislation does not specifically or categorically exclude pile-burn, stoker-combustion technologies from RPS eligibility. See M.G.L. Chapter 25A, Section 11F(b). The NOI notes that "[t]he language of the statute is not specific with regard to what would constitute 'advanced biomass power conversion technologies'." NOI at 2. The existing RPS regulations, however, preclude stoker and other pile-burn technologies from RPS program eligibility based upon a finding that pile-burn and stoker combustion units would never produce electricity as cleanly as fluidized bed units and therefore should not be considered "advanced." NOI at 3 and n.9; 3/6/02 letter to DOER, "Report of Joint Committee on Energy Regarding Final Proposed Legislation" at 2. Technology improvements in air emissions control have rendered this finding obsolete. Indeed, existing stoker-combustion units can now achieve NOx emission levels that are lower than those that have been required of *new* fluidized bed units in Massachusetts. NOI at 3-4 and n.13.

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[1] For example, at the time Public Service Company of New Hampshire ("PSNH") received its draft advisory ruling for the conversion of its coal-fired Schiller Station Unit 5 to a coal and wood-fired unit, PSNH estimated the conversion cost at approximately $69 million dollars, and projected a break-even renewable energy credit sales price of $25 in 2007. From 2008 to 2020, the break-even price projected steadily declined from $24 in 2008 to less than $10 in 2020. (PSNH direct testimony before the NHPUC in Docket DE 03-166, August 28, 2003). At the time of these projections, PSNH noted that renewable credit sales were occurring in the $30 to $40 per credit range. While PSNH's projections of project cost and break-even prices may have changed since it quoted these numbers in 2003, the point remains that at the time of eligibility determination the unit was not, and no other generating unit eligible under the RPS program is, subjected to sales price or output restrictions or price differentials. Also note that these break-even numbers quoted by PSNH do not include the benefit the Schiller Unit's economics will obtain from the federal open-loop biomass tax credit, which in testimony before the NHPUC, PSNH estimated to be about $5 million a year for the $69 million project.

Low-emissions are not the only basis upon which to find that stoker-combustion units are sufficiently "advanced" to include them in the RPS. The USEPA recognizes that stoker combustion units have advantages over other types of boilers, including fluidized bed boilers. Stoker combustion boilers have "fast response to load changes . . . improved combustion control, and can be operated with multiple fuels." USEPA, *AP-42: Compilation of Air pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* §1.6.2 (5th Ed. 2003). Consequently, the advantage that DOER finds in fluidized bed technology, fuel diversity, is not unique to that technology. Stoker combustion units can also provide fuel diversity. USEPA, *AP-42: Compilation of Air pollutant Emission Factors, Volume 1: Stationary Point and Area Sources* §1.6.2 (5th Ed. 2003).

1.3 Recommendation

(a) DOER should include stoker-combustion, pile-burn and similar technologies as RPS eligible units if they meet reasonable low emissions, and advanced biomass conversion technologies standards. These technologies should be allowed to participate in the RPS program on a level playing field basis and NOI provisions that have the unintended consequence of establishing standards at levels that effectively preclude participation by these technologies should be reviewed and revised to provide for low emission, advanced biomass power conversion technology standards that represent attainable levels of improvement.

2.0 THE RETROFIT REQUIREMENT AND THE 36 MONTH LIMITATION ON RPS PROGRAM ELIGIBILITY

2.1 NOI Proposal

(a) The NOI at page 13 provides that existing units that are retrofitted after 1997 to comply with the heat rate and emissions benchmarks (i.e., the low emission performance standard and the advanced biomass power conversion standard) would be exempt from the vintage waiver regulations. NOI Sections 2(e) and 3(a). The NOI also proposes to codify in regulation the principles of the April 2004 Biomass Retooling Guidelines, NOI at Section 3(a), with the implication that a generating unit that retrofits to meet the low emission and advanced biomass power conversion standards will be eligible to sell its entire output under the RPS program. DOER seeks to provide sufficient, but not excessive, financial incentive to generating units retrofitting under these provisions, and thus, the NOI proposes to limit the period of RPS eligibility to 36 months from the date such a unit commences operation under a statement of qualifications. NOI at Section 3(b), pages 13-14.

2.2 Discussion Points

(a) The NOI at Section 3(a) states that a new Section 14.05 will replace the April 2004 Biomass Retooling Guideline. The Biomass Retooling Guideline is a significant interpretation of the DOER RPS regulations because it provides the basis for distinguishing between vintage waiver units and new renewable generation units. As DOER is aware, this distinction is important because it determines whether a generating unit is RPS eligible for its

incremental output or its entire output, and hence has a significant effect on project viability and the supply increase expectations arising from the NOI's concepts.

(b) Under the April 2004 Biomass Retooling Guideline, the DOER interpreted the definition of Vintage Generation Units to apply only if both conditions stated in the definition exist. See 225 CMR 14.02 (definition of Vintage Generation Unit). The absence of either condition means the unit is not a Vintage Unit. One of the required conditions is that the unit meet all the requirements of 225 CMR 14.05 1(a). These provisions include the requirement that a unit be low-emission, combust an eligible biomass fuel, and meet the advanced biomass power conversion standard. This section also categorically excludes stoker-grate generating units from RPS eligibility. As the Biomass Retooling Guideline noted, that exclusion means stoker units which retool are new renewable generation units and not Vintage Units because they did not meet the 2 part definition of a Vintage Generation Unit. See April 2004 Biomass Retooling Guideline, Section 2.2, at 2-3.

(c) As the April 2004 Biomass Retooling Guideline notes, this same rationale applied when the DOER determined that the entire output of Schiller Station Unit 5 would be RPS eligible upon retooling. In that case, the unit was pre-1997 but did not meet the Vintage Generation Unit definition because it combusted coal, an ineligible fuel under 225 CMR 14.05 1(a). *Advisory Ruling for Public Service Company of New Hampshire-Schiller Station Unit 5*, October 27, 2003 at 3, and April 2004 *Biomass Retooling Guideline* at Section 2.3, pages 3-4.

The DOER should maintain a consistent regulatory interpretation of its RPS regulations on this important point, and, whether as new generation or as a new category of Vintage Generation (see recommendation comment 2.3(c) below) provide that the entire output of a retrofitted pre-1997 stoker-grate unit is RPS eligible.

(d) Providing for the eligibility of the entire output of pre-1997 retrofitted stoker-grate units does not mean that reasonable conditions on the length of eligibility can not be created to mitigate program uncertainty for existing participants. See Recommendation Comment 2.3(c) below. These conditions, however, should balance interests and should not have exclusionary effect. The NOI's proposed 36 month limitation should be revised because it will have an exclusionary effect. Given the capital costs required for stoker-grate retooling, the uncertainty of renewable energy credit prices, and unit operational cost uncertainty (e.g. wood fuel prices) it is unlikely that any generating unit owner will incur those risks for the opportunity to attempt to be repaid that capital, cover the unit's increased operating costs of add-on pollution control devices, and earn a return during a 36 month period. Recall that one commentator in the July 28, 2005 Stakeholder Meeting provided data indicating that a 22 MW biomass unit would need a price of $33 per renewable energy credit to break-even. This break-even number does not provide any revenue for profit, federal taxes, or long term maintenance needs and hence is a conservative estimate.

(e) Our recommendation at 2.3(c) below presents two alternative categories for creating a reasonable period of RPS program eligibility: either as a vintage generation unit or a new unit. Classification as vintage, for these purposes only, however, should not require the generation of a base amount of RPS *ineligible* MWh output. Given market rates for energy, and

in the absence of renewable credit revenue, those base amount MWhs are likely to be generated at a loss. The need to generate subsequent MWhs at a price sufficient to cover that loss due to inadequate market rates for energy, and the continued market energy price loss on the subsequent MWhs, imposes ever increasing upward pressure on the renewable energy credit price needed. This situation could be mitigated by allowing all MWhs to be RPS eligible for a reasonable time period.

2.3 Recommendations

(a) DOER should clarify in its regulations that a biomass generating unit which retrofits after 1997 will be eligible to sell its entire output into the RPS program, subject only to any restrictions arising under our recommendation comment at 2.3(c) below.

(b) DOER should clarify that the retrofit requirement for biomass generating units retrofitting after 1997 will be met as long as a retrofit is done to meet at least either the low emission performance standards or the advanced biomass power conversion standard. Here, we note that no practical retrofit of a heat rate is possible if units must meet the NOI's proposed heat rate standards. See our comments in Section 3 and our proposed revised advanced biomass power conversion standard in Section 3.3(b) below.

(c) DOER should eliminate the 36 month limit on RPS eligibility. We propose that it be replaced with a limitation in the range of 72 to 84 months from commencing operations under a statement of qualifications. During this period, the generating unit's entire output would be RPS eligible. To implement this RPS time eligibility limitation, DOER could consider: (i) establishing an additional category of Vintage Waivers, see 225 CMR 14.05(2), under which a biomass unit that was retooled post 1997 would have a time limit on RPS eligibility rather than be subject to the incremental output limitation. The request that Vintage Waiver Units demonstrate emission rates consistent with comparable biomass units, see 225 CMR 14.05(1)(a), (6)(b) and (c), would be replaced for such units with the requirement to meet the low emissions performance standard, or (ii) DOER could continue to uniformly apply the rationale in the April 2004 Biomass Retooling Guideline and also require a 72 to 84 month range limitation commencing with the start of operations under a statement of qualifications.

3.0 ADVANCED BIOMASS POWER CONVERSION TECHNOLOGY PERFORMANCE STANDARD.

3.1 NOI Proposal

The NOI proposes the use of a net heat rate method to determine whether a biomass generating unit meets the advanced biomass power conversion technology requirement. Under the NOI, net heat rate is defined as the higher heating value of the fuel, expressed in Btu's, divided by the net electrical output of the generation unit. Net electrical output is the gross electrical output less the electrical output consumed within the generation unit (*i.e.*, the "parasitic load"). The NOI net heat rate method deducts the KWhs consumed by the parasitic load from the electrical output, but, as is appropriate for a net heat rate calculation, the Btu value of the fuel used to produce the KWhs consumed by the parasitic load is not deducted from the Btu number used in the net heat rate ratio. The NOI also proposes to establish maximum net heat rates for

generating units based on a unit's capacity and establishes different heat rates for fluidized bed and non-fluidized bed units. The NOI states that fluidized bed units are "inherently less efficient due to the heavier parasitic load of fans,"[2] and proposes to allow these units to qualify under the RPS program at higher net heat rates than those applicable to non-fluidized bed units.

3.2 Discussion Points

(a) The NOI does not propose any protocols to be used for calculating heat rate. The calculation methodology to be used for determining biomass fuel heat rate is a significant issue because the Btu value of a biomass fuel constantly changes due to the changing moisture content of the various biomass fuels. Unlike conventional fossil fuels, the moisture content of biomass fuels varies seasonally due to ambient conditions, and will also vary daily, and from sample to sample. Typically, the moisture content of whole tree chips, bark and sawmill residues ranges from 40 to 55 percent. The moisture content of construction and demolition debris derived wood fuel[3] and of other dry wood fuels, such as crushed wood pallets and ground trimmings from wood products manufacturing, ranges from 10 to 30 percent. Btu content determinations are further complicated if the unit is able, at any time, to combust a variable mix of these different moisture content fuels. This variability in moisture content and in the biomass fuel mix itself makes accurate determination of the Btu value of the fuel and the corresponding heat rate problematic. For a 10 MW to 25 MW generating unit, a five percent change in fuel moisture will create a one percent change in boiler efficiency. Larger generating units will experience a four percent decrease in boiler efficiency.

The net heat rate method, in addition to computational difficulties, also creates a reporting issue because the ISO-New England generation information system ("GIS"), does not presently collect heat rate data for RPS purposes. DOER should consider remedying this reporting issue by adopting a performance standard that reports data in a form used by the GIS.

(b) The selection of a heat rate standard can also adversely affect the amount of renewable credits available for sale from an otherwise eligible unit and hence adversely impact the determination of whether it is cost effective for an existing unit to enter the RPS program. This situation occurs because typically the highest wood fuel moisture content occurs in the Spring. If the heat rate selected is inadequate to allow for this seasonal variation in moisture content, then the unit may not meet heat rate eligibility requirements each Spring and could lose an entire calendar quarter's worth of renewable energy credit revenue. As a consequence, the renewable credit market would also be affected as the number of credits available for sale each

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[2] In contrast to this observation on fluidized bed heat rate in the NOI, one commentator on the DOER's initial RPS regulations stated that its fluidized bed units were "New England's most efficient (*e.g.*, heat rate) biomass power plants." See *Comments of Ridgewood Power, LLC, et al.*, October 25, 2001, at 1.

[3] To achieve heat rate reductions, existing units may be forced to use the lower moisture content C&D fuels. This would have the unintended effect of causing reductions in the environmental benefits obtained from using higher moisture content whole tree chips as fuel. Also note that New Hampshire has placed a moratorium on the combustion of C&D fuels until at least July 1, 2006. *See* H.B. 517, 159th Sess., 2005 N.H. Laws _____. New Hampshire is also studying whether C&D fuels should be combusted at all. *See* S.B. 215, 159th Sess., 2005 N.H. Laws _____. House No. 3280 is pending in the Massachusetts legislature. This bill would limit C&D combustion to no more than 20%. House No. 3280, 184th Gen. Ct., 2005 Mass. Laws _____. Thus, the lower moisture content fuels may not be available at levels sufficient to increase the supply of biomass REC sellers.

Spring would be reduced. Also note, that if the heat rate selected is too low, it can adversely affect generating units that are dispatched because operation at reduced loads has the effect of increasing the unit's heat rate.

(c) Given the nature of the fuel combusted and technology employed in biomass units, the use of a net heat rate as the sole measure of a biomass unit's efficiency results in disparate treatment between fluidized bed units and non-fluidized bed units under the NOI, particularly when there are different standards for two technologies. In effect, for RPS program eligibility, the NOI's heat rate efficiency measure requires that non-fluidized bed units, such as stoker grate units, be more efficient than the newly constructed advanced fluidized bed technologies. In the case of a fluidized bed unit, the NOI heat rate method indirectly corrects for the parasitic load fuel Btu value and any other operating and technology inefficiencies by providing for RPS program eligibility based on a higher heat rate. With this heat rate differential, fluidized bed units, which have already been deemed an advanced biomass conversion technology in DOER advisory rulings, *see Advisory Ruling for Public Service Company of New Hampshire – Schiller Station Unit 5,* October 27, 2003 at 4-5, are given an advantage over non-fluidized bed units under the NOI heat rate concept.

The greater heat rate performance standard placed on stoker grate units is all the more problematic in terms of creating, in the near-term, an additional supply of generating units capable of providing renewable energy credits under the Massachusetts RPS program when one considers that one of the most likely near-term sources of additional supply are existing generation units employing stoker grate technology. None of the stoker grate unit signatories to these comments can meet the heat rates set forth in the NOI's table 1 for non-fluidized bed units and to their knowledge, no other existing stoker unit in New England can meet those heat rates and comply with the emission limitations of the NOI.[4] Thus, the use of the table 1 heat rates for non-fluidized bed units will not create an increase in the supply of renewable energy credits from existing stoker grate units. To remedy the disparate treatment between biomass technologies, DOER should consider using a performance standard for the determination of whether a generating unit is an advanced biomass power conversion technology that can be uniformly applied across the range of biomass combustion technologies. Our recommendation at Section 3.3(b) presents such a standard.

(d) The NOI heat rate ratio for non-fluidized bed units also has the effect of penalizing stoker grate units for providing cleaner air due to the impact on heat rate of air emission control technologies, such as SCR technologies, and advanced over-fire air systems. Employing add-on pollution control technology will be necessary to reduce air emissions. The technologies required to meet the proposed low emission performance standards will likely increase the parasitic load of a unit and hence increase the number of Btu's used in the NOI's heat rate ratio. Use of these add-on pollution control technologies can be expected to add between a half a MW to a MW of additional parasitic load for generating units in the 10 MW to 25 MW range. Larger units will experience a greater increase in parasitic load due to the addition of these pollution control technologies. This means for example, that while an existing stoker grate unit can meet air emission levels for biomass fuel combustion that will be the same

[4] Compliance with emissions limitations will require add-on pollution control equipment that will increase parasitic load and hence increase the number of BTUs in the heat rate ratio.

as or better than a fluidized bed unit, under the NOI heat rate performance standard it must do so at heat rate levels significantly below those provided for the fluidized bed. The lower the heat rate requirement, the more difficult it will be to add pollution control and other environmentally beneficial technologies to the power plant and continue to meet the required heat rate.

(e) To the extent the NOI seeks, among its policy goals, to create additional near-term supply of renewable energy credits from existing biomass units, it should recognize that the heat rate of an already constructed unit is very difficult to change. In terms of the RPS program and this NOI, the heat rate of existing units should be viewed as a given.[5] Essentially, heat rate is an initial business decision at the time of project development. It is an allocation of capital between expected operating costs and capital costs that balances the expected cost of the Btu's (fuel) to be combusted with the capital cost of the selected combustion technology (*e.g.*, the purchase of a higher or lower pressure boiler that will consume more or less Btu's to produce its given electrical output). Given this fact, rather than base heat rate distinctions on whether the unit is a fluidized bed or non-fluidized bed, the DOER may wish to consider distinctions based on whether the unit is an existing unit or new proposed construction.

3.3 Recommendations

(a) Because heat rate for variable biomass-fueled units is not capable of precise and consistent measurement and application of the NOI heat rate concept results in disparate treatment of biomass technologies, DOER should consider replacing the net heat rate performance standard with a standard that measures efficiency based on pounds of pollutant emitted per net MWh of generation. *See* 3.3(b) below. This measure, or performance limit, will be determined based on a formula that uses a single heat rate constant for all biomass technologies and the applicable emission limits noted in Section 4. The formula uses the fluidized bed heat rates in NOI table 1 as the heat rates to be used by all units. This has the advantage of treating all biomass combustion technologies and fuels equally. The methodology in Section 3.3(b) will not preclude RPS program eligibility for existing biomass technologies which, for example, can provide lower NO_x air emissions than the biomass units already approved for program eligibility under either advisory rulings or statements of qualification.

This recommendation also has the benefit of producing a standard that results in data reporting for compliance purposes that is consistent with the data reporting and disclosure requirements of the *GIS, New England Power Pool Generation Information System Operating Rules*, Rule 2.5 and Appendix 2.4, and with the Commonwealth's rules governing the restructuring of the electric industry. *See* 220 CMR 11.06(5)(c). This methodology is consistent with DEP's present reporting requirements for emissions from other units, such as coal-fired generation. For example, Brayton Point has a NO_x limit of 1.5 lbs/MWh.

Furthermore, this recommendation is consistent with the RPS statutory requirements for RPS program eligibility because it uses a calculation (see Section 3.3(b) below) that gives effect to the low emission criteria and to the advanced biomass power conversion technology criteria.

[5] Retrofitting a stoker unit to replace the boiler with a fluidized bed boiler will not improve the heat rate because, as noted in the NOI, fluidized bed units are "inherently less efficient due to the higher parasitic load," and have been accorded a higher heat rate under the NOI than the heat rate provided for stoker units.

The calculation imposes a performance standard for advanced biomass power conversion technology purposes stated in pounds of emissions per MWh of electrical output that is derived from emission limitations and heat rate.

(b) We recommend that DOER use the following calculation, to be performed separately for each applicable emission limit, to create the standards to determine compliance with the advanced biomass power conversion technology requirement.

[Emission Limit x [1 MMBtu / 1,000,000 Btu]] x [Heat Rate Constant x 1,000 KWh / MMBtu] = Performance Limit Standard in lbs/MWh.

Example Using NO_x Emission Limits:

.065 lbs/MMBtu x 16,000 Btu/KWh = 1040/1000 = 1.04 lbs NO_x/net MWh.

where:

"Emission Limit" equals the air emissions limitations set forth in Section 4 for each of NO_x, CO, PM and VOC stated in lbs/MMBtu for the particular capacity of the biomass unit.

"Heat Rate Constant" means:

- 14,500 Btu / KWh for a unit equal to or greater than 25 MWs
- 16,000 Btu / KWh for a unit equal to or greater than 10 MWs and less than 25 MWs
- 19,000 Btu / KWh for a unit equal to or greater than 1 MW and less than 10 MWs.

"Performance Limit" is the result of the computation and is stated in lbs / per MWH. The Performance Limit is the set of standards a unit must meet to be an advanced biomass power conversion technology. The various Performance Limits are:

(i) For units using the 14,500 Btu / KWh Heat Rate:

- NO_x Performance Limit = 0.9425
- CO Performance Limit = 2.175
- PM Performance Limit = 0.1595
- Non-Methane VOC Performance Limit = 0.1595

(ii) For units using the 16,000 Btu / KWh Heat Rate:

- NO_x Performance Limit = 1.04
- CO Performance Limit = 2.4
- PM Performance Limit = 0.24

- Non-Methane VOC Performance Limit = 0.16

(iii) For units using the 19,000 Btu /KWh Heat Rate:

- NO_x Performance Limit = 1.77
- CO Performance Limit = 4.75
- PM Performance Limit = 0.285
- Non-Methane VOC Performance Limit = 0.19

To qualify as an advanced biomass conversion technology, a unit cannot exceed the Performance Limit measured over the applicable reporting period. This reporting period for CEMs monitored emissions would be based on the quarterly average of all CEMs data during the quarter. PM testing would occur at the frequency stated in the Unit's Title V air permit. Compliance with the Performance Limit will be determined based on the actual number of pounds of each applicable pollutant emitted during the compliance period and the actual net MWh produced during the compliance period.

4.0 THE LOW EMISSIONS PERFORMANCE STANDARDS.

4.1 NOI Proposal

The NOI proposes to establish pollutant-specific emission standards and presents Tables 2 and 3 as the basis for discussion. The NOI describes Table 2 emission levels as the maximum acceptable levels and describes Table 3 emission levels as achievable "through technology transfer from other combustion sources." The NOI seeks comment to develop the acceptable emission level for the various pollutants within the range created by the emission levels in these Tables.

4.2 Discussion Points

(a) Tables 2 and 3 create a range of NO_x emission levels of between .075 lbs/mmBtu and .015 lbs/mmBtu, respectively for new or retooled units having a capacity of greater than 10 MWs. While the Table 2 NO_x level is achievable, the Table 3 NO_x level is unlikely to be achievable because the technology used to achieve these lower limits, in coal plants for example, is not transferable to a biomass-fueled generating unit. Coal-fired SCR technology can achieve a 90% NO_x reduction because the catalyst is placed in the high dust, hot gas stream location. Positioning an SCR in this location is not possible with biomass units due to the high load of large particle ash, and the presence of sodium and potassium in the fly ash. Sodium and potassium, which are not present in material amounts in coal, will "poison" any catalyst technology used to remove NO_x. The presence of these elements reduces the catalyst reactivity and thereby produces higher emission levels. In addition the high dust load will quickly plug the catalyst. To mitigate the plugging effect caused by the high dust load, and the "poisoning" effect of sodium and potassium, biomass NO_x catalysts are located in a clean gas location, downstream of the particulate removal device. In this location the gas stream is cooler than the gas stream location for a typical coal unit SCR and hence must be reheated to achieve the temperature

necessary to create the catalytic reaction. The temperature reheat level involves an economic balance of heat inputs and hence design temperature levels are adequate to trigger the reaction and NO_x removal, but are not as high as if the catalyst were capable of being located in the hot gas stream.

(b) The ammonia slip emission level is primarily a function of the amount of NO_x reduction sought and the variable Btu and moisture content of the biomass fuel combusted. The variable nature of the biomass fuel makes calculating the amount of NO_x in the flue gas, and hence the amount of ammonia needed for NO_x control, problematic resulting in higher levels of ammonia slip than would occur with a fuel having a constant caloric value.

There are a number of methods used to measure ammonia slip on an intermittent or grab sample basis, such as EPA method CTM 027. Continuous monitoring of ammonia slip at low levels has proven to be inaccurate and unreliable. Ammonia slip measurement is difficult due to the potential for losses in the sample line and water removal system. In addition ammonia reacts with other components to form ammonium salts, which can deposit and clog sample line, the water removal system, and analyzers. The differential NO_x method where ammonia is oxidized to NO and the difference of the two readings represents the ammonia present is a more reliable method. At the levels contemplated under the NOI, however, even this method can produce questionable results. An intermittent or grab sample such as EPA method CTM 027 may be more appropriate and hence, ammonia slip measurement protocol should not involve the use of continuous monitoring equipment.

(c) CO catalyst technology on combined cycle natural gas units can achieve a 90% or greater reduction in CO. These levels, however, are not commercially achievable on a retooled biomass unit. A typical biomass unit combusting whole tree chips will produce a seasonal range of 0.15 to 0.3 lb/mmBtu of CO. Use of a CO catalyst can be expected to produce a 50% reduction in these CO levels on a 365 day rolling average basis when the catalyst is located in the tail end of the generating unit. For example, a biomass unit in Northern New Hampshire has achieved levels of .08/mmBtu during optimum dry fuel conditions with a CO catalyst located at the tail end. In comparison, CO catalysts located in the high dust region are not as effective due to the poisoning effect of ash constituents and fouling. The high level of CO generated in combusting biomass fuel is significantly impacted by the moisture content of the fuel fired and varies significantly with ambient conditions and fuel types. It varies significantly between winter and summer seasons because most units maintain inventory in open storage piles. The combustion process must contend with combusting fuel mixed with snow and ice in the winter and increased moisture in the spring and fall due to heavy rains. Given the variability in CO levels some jurisdictions, such as New Hampshire, measure CO on a 365 day rolling average basis. If a 365 day average is used, CO levels in the 0.1 lb/mmBtu range are likely to be achieved. If a monthly limit is required, a more conservative 0.15/lb mmBtu limit would be needed due to the above-noted fuel-moisture conditions.

(d) Table 3 levels for PM are unlikely to be met by existing stoker-grate designs or other biomass combustion technologies. The capital costs needed to meet such levels when combined with the capital costs needed to meet the other low emission requirements, and the

effect of the proposed RPS program eligibility time period limitation, See Section 2.2(d), may make RPS program participation by existing units prohibitive.

(e) Catalyst technology will be used to achieve NO_x and CO reductions. These catalysts are oxidizing and, absent the use of large amounts of construction and demolition debris as fuel, should convert most of the VOC emissions from the furnace.

4.3 Recommendations

(a) DOER and DEP should consider adopting as the low emission standards for NO_x, Ammonia, CO, PM_{10} and VOCs the following amounts, which unless otherwise noted, are stated in lbs per mmBtu:

	For Units Equal To Or Greater Than 25 MWs	**For Units Equal To Or Greater Than 10 MWs and Less Than 25 MWs**	**For Units Equal To Or Greater Than 1 MW and Less Than 10 MWs**
NO_x	0.065	0.065	0.093
Ammonia	13 PPM at 3% O_2	10-13 PPM at 3% O_2	25 PPM at 3% O_2
CO (monthly rolling average)	0.15	0.15	0.25
PM_{10}	0.011	0.015	0.015
VOC (Non-Methane)	0.01	0.01	0.01

Significant capital expenditures will be needed to reduce emissions to these levels at existing biomass units. These units can be expected to retool to add new technologies for NO_x and CO control. Certain units may also require additional equipment to meet the PM_{10} levels. Unlike the Table 3 levels, however, with the addition of the above-noted pollution control technologies, these levels are commercially achievable.

These emission levels will be monitored and, except in the case of PM_{10} (See 4.3(c)) and VOC (See 4.3(d)), are proposed to be reported quarterly and annually. These emission levels, calculated over the applicable time period, are the not to exceed low emission performance standards. The emission levels provided in Section 4.3(a) are also the Emission Limits to be used in creating the advanced biomass power conversion standard discussed in Section 3 above. See Section 3.3(b).

(b) DOER and DEP should consider removing the SO_2 emission level for biomass units that certify or by permit can only combust whole tree chips, bark, sawmill residues, and minor amounts of start-up fossil fuel because SO_2 is not present in any significant amount when

combusting these fuels. This change would also eliminate the need and cost associated with the monitoring and reporting of this pollutant.

(c) DOER and DEP should consider revising the testing and reporting frequency for PM_{10}. A PM test costs approximately $5,000.00, however, levels of this pollutant will not change in the absence of a technology change. Thus, frequent testing and reporting of PM levels adds unnecessary costs. Continuous opacity monitoring is required at all generating units and their Title V air permit requires a compliance and assurance monitoring plan that insures equipment is in satisfactory working condition. We propose that PM_{10} be measured once every 3 to 5 years or as provided in a generating unit's Title V air permit.

(d) Ammonia slip should be measured by the EPA method noted above, and reported annually.

(e) While the NOI at Tables 2 and 3 addresses monitoring and reporting periods, it does not explicitly state how emission data is to be determined over the reporting period. The DOER and DEP should clarify that the emission levels reported will be quarterly averages. The PM and VOC will be reported using historic test data as the emissions rate. CO will be reported as the quarterly average of a rolling 365 day average. Quarterly averages are consistent with the GIS reporting requirements and take into account the higher emission levels that may occur during unit start-up, momentary upset conditions, and maintenance periods for control equipment.

5.0 MISCELLANEOUS ISSUES.

(a) The NOI seeks comments on practical ways of increasing the stringency of emissions limits over time. At the Stakeholders' Meeting, DEP proposed the issuance of a number of tables, each containing more stringent requirements and each tentatively becoming effective on a date in the future. According to this proposal, a public hearing would be held to determine whether the limits set in each table were actually achievable, and the table would not become effective without a finding that the limits could be achieved with available technology.

We provide the following recommendations on this concept:

(i) New emissions limits and other regulatory standards should not be applied to a facility once that facility possesses a statement of qualification. Although DEP and DOER stated this intention at the Stakeholders' Meeting, we recommend that this policy be made explicit in DOER's regulations.

(ii) DOER should continue its policy of not requiring retrofitted units to meet the same emissions limits and advanced biomass power conversion standards that newly designed and constructed units might be able to meet. See *Advisory Ruling for Greenville Steam Company*, July 8, 2004 at 3 (stating that NO_x emission rate expectations for new units are lower than the rate that would be regarded as low-emissions for a retrofitted plant).

(iii) New emissions limits applicable to new RPS applicants should be developed in consultation with equipment manufacturers and plant operators to insure the standards are viable and commercially attainable.

(b) Section 4(a) at page 14 of the NOI proposes that statements of qualification be given expiration dates. We recommend that all generating units be given a standard period of 2 years from issuance of the statement of qualifications during which to commence RPS-consistent operations. Generating units that require longer than two years to become operational should provide DOER with evidence that a longer construction period is necessary as part of their application for a statement of qualification. DOER should define "preconstruction permits" and their "equivalents" if this is to be the level of proof required to be submitted with the application.

(c) Section 4(b) at page 14 of the NOI proposes a one year expiration period for advisory rulings. This seems unnecessary given that advisory rulings, by their nature, are merely advisory and do not secure any rights. All generating units should be required to comply with the standards that are in effect at the time they apply for statements of qualification. Giving effect to advisory opinions for any period of time would elevate advisory opinions to the level of statements of qualification, would be inconsistent with DOER's past statements on the effect of advisory rulings, and would encourage rather than discourage their use.

Submitted on Behalf of:

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